SPE

Society of Petroleum Engineers

SPE 19101

Four Pressure Buildup Analysis Techniques Applied to Horizontal and Vertical Wells With Field Examples

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ABSTRACT

Pressure build-up analysis of Devonian shale gas reservoirs is very critical and essential for determining the reservoir formation properties such as the flow capacity (Kh), skin factor (S), and the average reservoir pressure ($\bar{P}$). Due to the complexity of the shale reservoir (its typically very low permeability and the presence of a dual porosity system), valid and accurate results of pressure build-up analysis are important to the optimization of individual well completions or depletion plans for gas reservoirs in the shale. Horizontal wells may allow operators to take better advantage of the shale fracture systems and anisotropic flow regime, but they present a new challenge for well testing and analysis.

This paper documents a technical procedure with field examples, using pressure build-up data from horizontal and vertical wells, to assist the reservoir engineer in evaluating the reservoir prior to any decision-making process. This procedure implements two conventional build-up analysis techniques: (1) type curve matching, and (b) Horner's technique. Pressure and pressure-derivative values are used to estimate values of skin, flow capacity, and average reservoir pressure. A newly-developed technique known as the rectangular hyperbolic method (RHM) is implemented in the pressure build-up analysis for comparison to results determined by the previous techniques. The RHM technique is accurate/valid for estimating the various reservoir properties and, in particular, the average reservoir pressure. In addition, reservoir engineering simulation is used to verify the results of the various techniques by using either the pressure build-up data or the production history for the history matching process.

References and illustrations at end of paper.

INTRODUCTION

The major purpose of well test analysis is to determine critical formation properties of potential value in optimizing an individual completion or optimizing the depletion plan for a reservoir.

Build-up and drawdown of time-pressure data from unconventional shale-producing wells presents a challenge to reservoir engineers. Due to the low permeability and the presence of a dual porosity system in the shale, accuracy in the data analysis is a major factor for determining/estimating the various reservoir parameters associated with the analysis.

In this regard, several conventional techniques in addition to a newly developed technique were used to generate a step-by-step procedure for estimating values of formation flow capacity (Kh), Skin factor (S), and average reservoir pressure ($\bar{P}$). In addition, reservoir simulation was used to enhance the accuracy of the results.

Type curve matching and Horner's technique were the two conventional techniques implemented in the pressure build-up analysis. Furthermore, a newly-developed technique known as the Rectangular Hyperbolic Method (RHM) was used for comparison of results determined by the conventional techniques.

The validity and the accuracy of this practical procedure was verified using pressure build-up data from horizontal and vertical shale gas wells. Correlations of the reservoir parameters via the various analysis techniques enhanced the confidence in the results and hence assisted the reservoir engineers in evaluating the reservoir prior to any decision-making process.

BACKGROUND

Geologic and Reservoir Characteristics of the Devonian Shale: The Devonian shales of the Appalachian Basin constitute one of the largest worldwide concentrations of organic carbon and gas in-place. This complex sequence of source rock and reservoir has served as the focus of gas drilling for the past 50 years. The bulk of the production has been from highly fractured, historically developed areas such as southwest West Virginia. In general, the wells are shallow (averaging 3500 feet (1067 m) in depth) and have a low initial, unstimulated open flow.[1]

The target interval is the organically rich "black shale" that serves as a combination of source bed, reservoir, and seal in multiple stratigraphic horizons. Gas production is dominated by natural fractures and other permeability channels. The resource includes free gas in the natural fracture system and in the rock matrix, plus adsorbed gas on the surfaces of the organic kerogen.

Due to the complexity of the shale formation, and in particular, its low permeability and the presence of a dual porosity system, predictions/estimations of the various reservoir properties using conventional analysis techniques applied on pressure-time data becomes difficult. The uncertainty in the analysis tecnniques and characterization of the shale reservoir resulted in various research projects/publications to enhance the understanding of the shale reservoir in the areas of geology, extraction, production, and well test analysis. Recently a number of major studies and activities have been/are being completed under the Eastern Gas Shales Projects (EGSP) that provided foundation for this study. Furthermore, under the sponsorship of the U.S. Department of Energy/Morgantown Energy Technology Center (DOE/METC), several reports and publications resulting from analytical and field operations provided a database information on the fracture system, stratigraphic sequence, and gas content of the shale. In addition, average reservoir properties were estimated for areas/regions of study and used to predict/evaluate the study areas productivities through reservoir simulation.

Although certain shale matrix properties are very similar, the variation and uncertainty in reservoir properties, such as average reservoir permeability, reservoir pressure, skin, and fracture spacing and orientation, are detected between various shale wells. The sensitivity of the above properties to the prediction/analysis techniques, dictates a thorough understanding of the different procedures/techniques used for the analysis, and hence an accurate determination of these properties.

Well Testing Techniques - Build-up Analysis: Single and multiple well testing are means used to predict reservoir properties by implementing various analysis techniques. In this study we will devote our efforts to single well pressure build-up testing. This type of testing required shutting-in a producing well. The most common and simplest analysis technique requires that the well produce at a constant rate, prior to shut-in, either from start-up or long enough to establish a stabilized pressure distribution.[2] The pressure is measured immediately before shut-in and is recorded as a function of time during the shut-in period. The resulting pressure build-up curve is analyzed for reservoir properties and wellbore condition. Various analysis techniques of build-up pressure data are used to compute/estimate the various reservoir properties. In this study, four analysis techniques were used to estimate the shale reservoir properties. These techniques are: (1) type curve matching technique, (2) Horner's technique, (3) RHM technique, and (4) computer reservoir simulation technique. A detailed discussion of the four analysis techniques follows:

Type curve matching and Horner's technique have been widely used in the petroleum industry.[3] In addition, type curves have been thoroughly discussed in the literature. Earlougher has provided a very good explanation of dimensionless variables in SPE Monograph No. 5.[2] In short, type curves are log-log plots of dimensionless variables that provide generic solutions to fluid flow problems in homogeneous or fractured reservoirs. The most common representation of type curves are log-log plots of dimensionless pressure versus dimensionless time.[4] In addition, type curves have also been introduced in terms of the pressure derivative whose uniqueness offers an advantage in well test data analysis.

Computer reservoir simulation or history matching was used as an analysis tool to enhance the accuracy of the results. The analytical tool is a three-dimensional, single phase, dual porosity reservoir simulator. The dual porosity model simulates gas production/pressure performance from a naturally fractured reservoir. It depicts a dual porosity system in which gas is stored in the shale matrix and is subsequently released into the natural fracture network, which provides a transport mechanism for the gas when linked to the borehole.[5]. History matching consists of adjusting input parameters for a model until the simulated well or field performance is close to the actual historic performance. For this study, time-pressure data were used to predict the reservoir performance and hence estimate values of formation flow capacity and skin. The validity of these results depends on the accuracy of the input parameters.

A critical input parameter for this analysis is the initial average reservoir pressure. Determining an average reservoir pressure requires prior understanding/knowledge of the field reservoir pressure via initial testing. The accuracy of predicting/estimating the reservoir pressure leads to a better characterization of the various reservoir properties especially when dealing with low pressure-low permeability formations, such as the case with the Devonian shales.

A variety of articles/reports on well test analysis techniques were reviewed to determine a method for predicting the average reservoir pressure in both horizontal and vertical wells. It was concluded that the Rectangular Hyperbolic Method (RHM) defines the basis for the fourth analysis technique used in this study.

The concept of the RHM technique was initially defined by Mead[6] who suggested that the linear plot of time-pressure build-up points (after all wellbore storage, skin, and anomalous pressure effects have ceased) is a rectangular hyperbolic curve. Mead also concluded that it is possible to fit every build-up curve to a rectangular hyperbolic equation specific for that particular build-up. Furthermore, the asymptote to the time axis should be the static pressure for the area of influence.

At this point this concept was not proven mathematically, and the solution was based only upon intuition and empiric data. Hasan and Kabir[7] with further studies were successful to expand upon the work of Mead and present the mathematical basis for a simplified pressure build-up analysis procedure. The technique enables one to determine the average reservoir pressure directly from the field data without prior knowledge of the drainage shape and to obtain good estimates of Kh and S. The time-pressure data were matched with a rectangular hyperbolic equation having three constants (a, b, and c) where the solution using simple regression analysis will provide most satisfactory results. It is worthy to note that this method can be used with confidence only if it is applied to data that can also be analyzed by conventional semi-log methods. Further work was presented by Haugland[8] and Mead[9] suggesting modifications to the previous works performed on the RHM technique. After several reviews and applications, it is believed that the RHM technique suggested by Hasan and Kabir[7] could be the basis for characterizing the Devonian shale reservoirs and in particular assisting in determining the average reservoir pressure.

METHODOLOGY

A step-by-step procedure implementing the four aforementioned well test analysis techniques was generated to enhance the accuracy of predicting/determining the various reservoir properties as a result of single well testing.

As previously indicated, type curve matching and Horner's technique were the two conventional techniques used for the analysis. In addition, the RHM technique was implemented in the pressure build-up analysis for correlation purposes. The validity of these results was tested using a 3-D, single phase, dual porosity reservoir simulator to history match the time-pressure build-up data.

Analysis of gas pressure data required modifications to the conventional equations in order to evaluate the reservoir properties. The use of pressure squared (P^2) or pseudo pressure values ($m(P)$) instead of pressure (P) was essential for evaluating gas reservoir properties. The use of P^2 or $m(P)$ accounts for the compressibility and viscosity properties. Since the reservoir pressures in the study areas were established between 200-400 psia (1.4 - 2.8 MPa), values of P^2 versus time were appropriate for the analysis of the pressure data. It is worthy to note that as a rule of thumb, if reservoir pressure is less than 2000 psia (13.8 MPa), then P^2 values will establish a more accurate representation of the gas performance than that of P values.

As a first step in the time-pressure analysis, type curves for wells with wellbore storage and Skin effects in an infinite acting reservoir with a dual porosity system in a pseudo steady state flow regime were used. Log-log plots of change in pressure squared ($\Delta(P^2)$) and derivatives of change in P^2 ($d(\Delta P^2)$) with respect to time were generated and matched using the above dimensionless type curves. The wellbore storage effects, the formation permeability, the condition(s) of the wellbore/formation (damaged or undamaged), and the start of the semi-log straight line region were determined from the type curve matches. The accuracy of the estimated properties depended on the accuracy of matching the pressure-squared and the derivative pressure-squared curves simultaneously. Values of formation permeability and Skin factor were calculated using the type curve matching analysis. The following parameters were calculated/estimated as follows:

$$K(md) = \text{permeability} = \frac{1422\ q\mu ZT}{h} \left[\frac{PD}{\Delta P^2} \right]_{Match} \quad (1)$$

$$\emptyset C_t = \text{storability} = \frac{0.0002637}{\mu r w^2} \left[\frac{t}{\Delta tD} \right]_{Match} \quad (2)$$

The range of data determined from type curve matching that fall within the semi-log region was used for the Horner analysis technique. But prior to analyzing the build-up data using Horner's technique, the RHM technique was utilized to estimate the various reservoir properties using the pressure build-up data that was determined from the log-log plot falling within the semi-log region. This technique enables one to determine $\overline{P}$ directly from the field data without prior knowledge of the drainage shape. The Horner's equation for a well shut-in after producing at a constant rate in an infinite acting reservoir is written as:

$$P_{ws} = P_i - \frac{m}{2.303} \ln \left(\frac{tp + \Delta t}{\Delta t} \right) \quad (3)$$

This equation was modified and rewritten as follows:

$$P^2_{ws} = a + \frac{c}{b + \Delta t} \quad (4)$$

A simple linear regression can be performed on the variables P^2_{ws} and $1/(b + \Delta t)$ to determine optimal values of a, b, and c. Since the above equation is a three constant equation, a trial-and-error procedure has to be employed by assuming values of 'b' until a value of the regression correlation coefficient close to unity is obtained.

After determining the optimal regression correlation coefficient using the trial-and-error method, a straight line is plotted through these points, and values of 'a' and 'c' were determined, where:

a = y-intercept = $\overline{P}^2$ = average reservoir pressure-squared, psia^2
c = slope of the straight line, psia^2-hr
b = trial-and-error value, constant, hrs
m = slope of Horner straight line =

$\frac{1637\ q\mu ZT}{Kh}$ (gas wells), psi^2/log time.

Equations 3 and 4 were modified for gas wells and values of Kh and S were estimated as follows:

$$Kh = \frac{1423\ q\mu ZTb}{-c} \quad (5)$$

$$S = \frac{1}{2}\left[\frac{2.303}{m}(a - P^2wf) + \ln\alpha + 5.4316 - \ln tp - \ln\frac{K}{\phi\mu C_t r_w^2}\right] \quad (6)$$

where, $\alpha = \frac{tp-b}{b}$

Values of $\overline{P}$ using the RHM technique has an advantage over the conventional techniques because knowledge of neither the well/reservoir configuration nor the boundary condition is required for a routine build-up analysis.

After predicting the average reservoir pressure values using the RHM technique, a plot of pressure-squared versus Horner time $(tp + \Delta t)/\Delta t$, which incorporates the flowing time period, tp, was generated and a straight line passing through the stabilized pressure-time points having a slope 'm' was plotted. If enough pressure build-up data is available and the pressure has reached stabilization, a dual porosity system in the Devonian shale could be detected by having a straight line in the middle region with a slope m', where m' = 1/2 m. Values of average formation permeability, Skin factor, and average reservoir pressure were determined using Horner's technique. The following equations were used to determine K and S values:

$$K = \text{Permeability (md)} = \frac{1637\ q\mu ZT}{mh} \quad (7)$$

$$S = \text{Skin} = 1.151\left[\frac{P^2 1hr - P^2 wf}{m} - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right] \quad (8)$$

A comparison of Horner's technique with the type curve matching technique was evaluated at this stage. In addition to the above techniques, reservoir engineering simulation was utilized to history match the pressure and/or production profiles and predict the reservoir parameters. It is believed that a combination of these techniques will enhance and accurately estimate the various reservoir properties.

FIELD DATA APPLICATION

Example 1: Vertical Well A: Well A was producing from the Devonian shale at a rate of 9.80 mscfd (277 m³/day) for 165.5 hours at a well flowing pressure of 224 psia (15.4 MPa). The rate varied less than 1% during the test. The well was shut-in for a total of 142 hours where time-pressure data were recorded. Since all transient analysis were performed under bottomhole conditions, wellhead pressures were converted to bottomhole pressures which in turn were converted to $P^2/m(P)$ to account for the compressible nature of natural gas.

The pressure build-up data were analyzed to determine/estimate the average reservoir pressure, permeability, and skin. Figure 1 illustrates a log-log plot of change in P^2 versus shut-in time. The period of wellbore volume dominated data exists where the slope has a unit value or until log time = 0.3. Therefore, the semilog region begins after log time = 1.8. Results of type curve matching indicated a nondamaged region and a permeability value of 0.061 md. These results were obtained using Equation 1 at P_D = 0.92 and ΔP^2 = 10,000 psia² (68.9 MPa). Table 1 exhibits the various reservoir properties needed for this analysis.

As a first step the RHM technique was implemented to estimate an average value of reservoir pressure, $\overline{P}$, using the data falling within the semilog region. As mentioned earlier, a regression correlation coefficient close to unity was determined (r = 0.97546) by trial-and-error method using a Lotus 1-2-3 spreadsheet. Values of b and c were determined at 140 hours and -1487132 psi²-hr (-10252 MPa-hr) respectively. Therefore, using Equations 5 and 6, estimates of permeability and skin were determined at K = 0.06 md and S = -3.0, with a formation thickness h = 108 feet (33 m). From Figure 2, the value of average reservoir pressure is equivalent to the y-intercept, and hence, $\overline{P}$ = 325 psia (2.24 MPa).

In the next step, the data falling within the semilog region were analyzed using Horner's technique. An average value for reservoir pressure was estimated by determining the y-intercept of the Horner straight line (Figure 3) at Horner time equal to 1. The following values were estimated using Figure 3.

$\overline{P}^2$ = 105625 psia² (728 MPa) = $\overline{P}$ = 325 psia (2.24 MPa).
m = slope of Horner line = 13790 psia²/log time (95 MPa/log time).

Using Equations 7 and 8, values of K and S were determined at 0.056 md and -1.84 respectively.

Finally, the three-dimensional reservoir simulator was implemented to predict the average reservoir permeability and the overall performance of the reservoir by matching the time-pressure data during the drawdown and build-up periods. As a result of the simulation process the permeability was estimated at 0.075 md using a fracture spacing of 2.5 feet (0.76 m). A summary of the input parameters needed for the simulation process are exhibited in Table 2, and the time-pressure match is shown in Figure 4. Table 3 exhibits the results of the various techniques applied in characterizing the performance of well A.

Example 2: Horizontal Well B: A post-stimulation pressure build-up analysis was performed on Zone 1 along the horizontal wellbore section of Well B. After performing the frac job, Zone 1 was producing at an average production rate of 50 mcfd (1416 m³/day) for a period of 20 days at a well flowing pressure of 50 psia (0.35 MPa). When the rate reached stabilization, Well B was shut-in for a period of 13 days during which the reservoir build-up pressure was monitored in Zone 1. A plot of pressure build-up versus time is exhibited in Figure 5. Due to the complexity of production from the Devonian Shales, a log-log plot of ΔP^2 and $d(\Delta P^2)$ versus shut-in time was generated (Figure 6). A type curve for infinite acting reservoir was used where ΔP^2 and $d(\Delta P^2)$ curves were matched simultaneously on $C_{De}2S = 10^4$ curve. Match points of pressure and time were established and a value of reservoir permeability was estimated at 0.492 md using Equation 1, where P_D = 0.295 and ΔP^2 = 1000 psia² (6.9 MPa). Using Figure 6, the end of wellbore storage effects and the start of the semilog region were determined at log time equal to -1.0 and 0.5 respectively. Table 4 exhibits the various reservoir parameters needed for the analysis. At this point the RHM technique was implemented to estimate the average reservoir pressure, $\overline{P}$, using the data falling within the semilog region. A regression correlation coefficient close to unity was determined (r = 0.96875). Values of b and c were computed at 320 hours and -1,764,705 psia²-hr (-12166 MPa_hr) respectively. Using Equations 5 and 6, estimates of formation permeability and skin were determined at K = 0.303 md and S = 0.7, respectively, with a formation thickness, h = 247 feet (75 m).

From Figure 7 the values of average reservoir pressure is equivalent to the y-intercept and hence $\overline{P}^2$ = 31684 psia² (218 MPa), $\overline{P}$ = 178 psia (1.2 MPa). It is worthy to mention that prior to drilling Well B, the average reservoir pressure in the area was measured at 190 psia (1.3 MPa).

Finally, using the data falling within the semilog region, Horner's technique was implemented and values of permeability and skin were determined at 0.327 md and -0.88 using equations 6 and 8 respectively. The average reservoir pressure was established at $\overline{P}$ = 177 psia (1.2 MPa) with a Horner slope, m, equivalent to 5875 psia²/log time (40.5 MPa/log time). Table 5 exhibits the results of the various techniques used to estimate the reservoir properties for Well B.

CONCLUSIONS

The following conclusions are supported by the analysis presented in this paper:

- The four analysis techniques were successful in characterizing the Devonian shale reservoir parameters.
- The RHM technique was helpful in predicting/estimating the initial average reservoir pressure for both vertical and horizontal wells.
- The step-by-step procedure decreases the uncertainty in the predicted/calculated values of pressure, permeability, and skin for the Devonian Shales.

NOMENCLATURE

a = y-intercept/asymptote of rectangular hyperbola, psia²

b = trial-and-error constant of rectangular hyperbola, hours

c = constant of rectangular hyperbola, psi²-hr

C_t = total system compressibility, psia^{-1}

h = formation thickness, ft

k = formation permeability, md

m = slope of linear portion of semilog plot of pressure build-up curve, Horner's straight line, psi²/log time.

m' = 1/2 m

P_i = initial reservoir pressure, psi

$\overline{P}$ = average reservoir pressure, psi

P_{ws} = bottomhole shut-in pressure, psi

P_{wf} = flowing bottomhole pressure

m(P) = pseudo pressure, psia²/cp

$d(\Delta P^2)$ = pressure-squared derivative = $(d\,P^2/d\,t)\,t$

ΔP^2 = change in pressure squared = P^2ws-P^2wf, psi²

P_D = dimensionless pressure

q = volumetric producing rate, mscfd

r_w = wellbore radius, ft

r = simple regression correlation coefficient

S = skin factor, dimensionless

T = formation temperature, °R

t = time, hours

tp = producing time, hours

Δt = shut-in time, hours

Z = gas deviation factor, dimensionless

ϕ = porosity, fraction

μ = viscosity, cp

α = dimensionless constant introduced in Equation 6 (Reference 7)

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TABLE 1

WELL A - GAS RESERVOIR PROPERTIES

PARAMETER	VALUE
Gas Specific Gravity, S.G.	0.6731
Critical Temperature, T_c	378.53°R
Critical Pressure, P_c	663.49 psia
Gas Deviation Factor, Z	0.9450
Viscosity, μ	0.0102 Cp
Formation Temperature, T	538°R
Total System Compressibility, C_t	0.0019 $psia^{-1}$
Wellbore Radius, rw	0.2604 ft
Formation thickness, h	108 ft
Flowing time, tp	165.5 hours

TABLE 2

WELL A - SIMULATION VARIABLE LIST

PARAMETER	VALUE
Well Spacing	160 acres
Fracture Porosity, fraction	0.0005
Fracture Permeability	0.075 md
Matrix Porosity, fraction	0.01
Matrix Permeability	1×10^{-5} md
Fracture Spacing	2.5 ft
Anisotropy, Kx:Ky	1:1

TABLE 3

RESULTS OF THE BUILD-UP ANALYSIS TECHNIQUES APPLIED ON WELL A (VERTICAL)

TEST PROCEDURE	TECHNIQUE	K(md)	S
Build-up	Type Curve	0.061	Non-damaged
Build-up	RHM	0.06	- 3.0
Build-up	Horner	0.056	- 2.0
Drawdown and Build-up	Simulator	0.075	Non-damaged

TABLE 4

WELL B - GAS RESERVOIR PROPERTIES

PARAMETER	VALUE
Gas Specific Gravity, S.G.	0.7225
Critical Temperature, T_c	401.709°R
Critical Pressure, P_c	666.361 psia
Gas Deviation Factor, Z	0.980
Viscosity, μ	0.0107 cp
Formation Temperature, T	553°R
Total System Compressibility, C_t	0.0100 psi^{-1}
Wellbore Radius, rw	0.328 ft
Formation thickness, h	247 ft
Flowing time, tp	480 hours
Matrix Porosity, fraction	0.0173

TABLE 5

RESULTS OF THE BUILD-UP ANALYSIS TECHNIQUES
APPLIED ON WELL B (HORIZONTAL)

TEST PROCEDURE	TECHNIQUE	K(md)	S
Build-up	Type Curve	0.492	Non-damaged
Build-up	RHM	0.327	0.70
Build-up	Horner	0.303	- 0.88

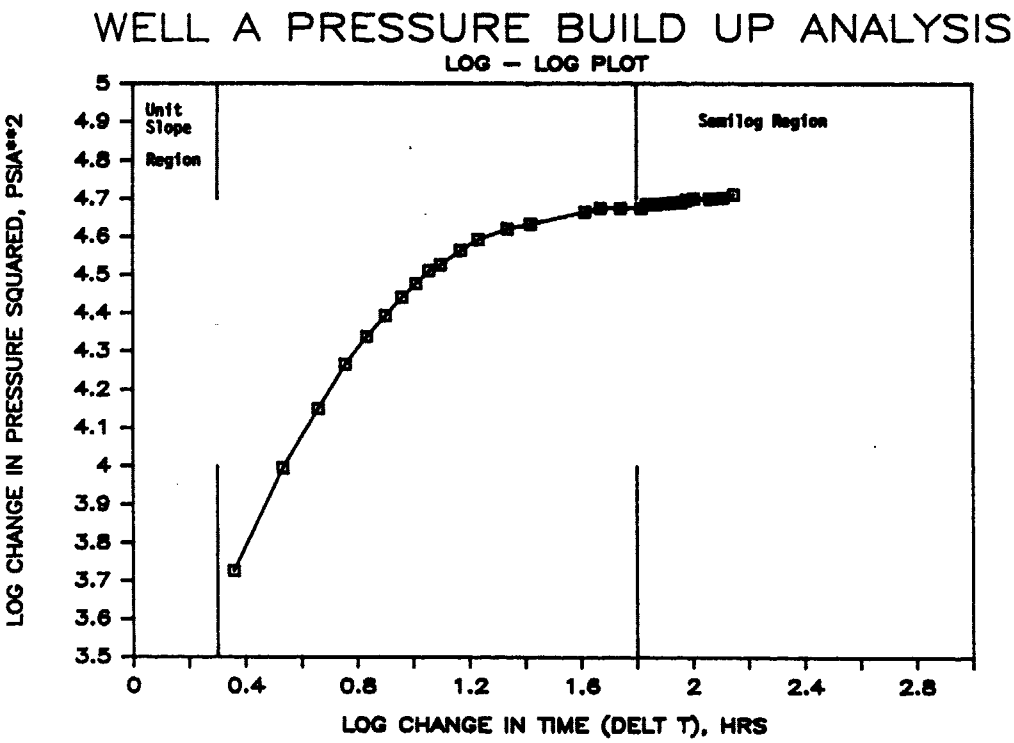

Figure 1: Log-Log Plot of Pressure-time Data for Vertical Well A

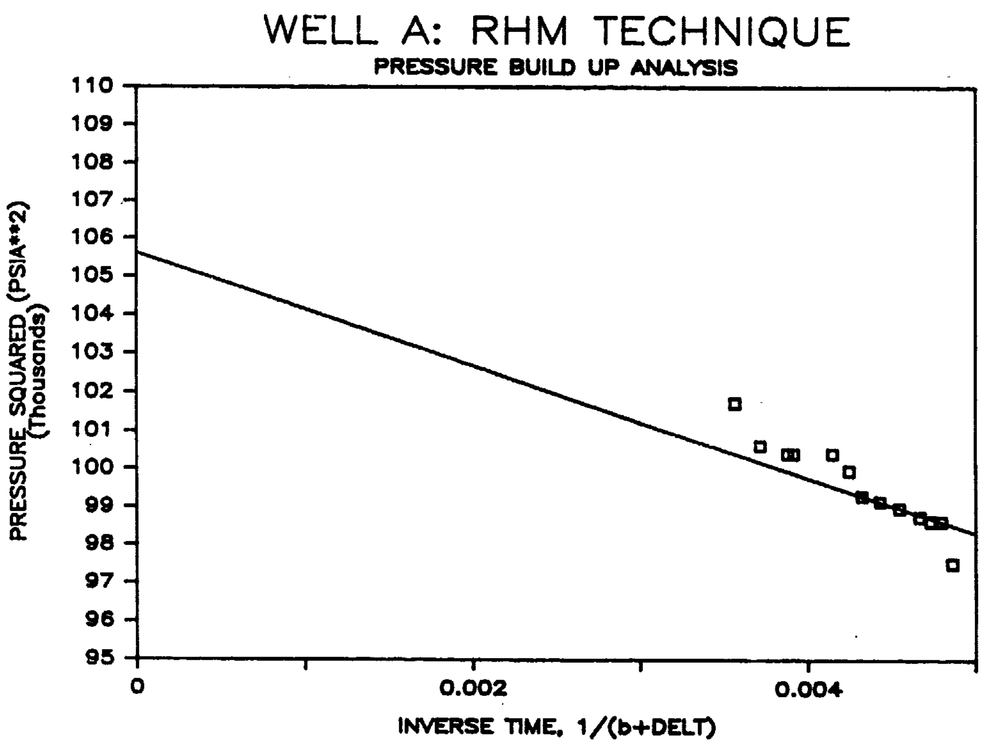

Figure 2: RHM Plot for Vertical Well A

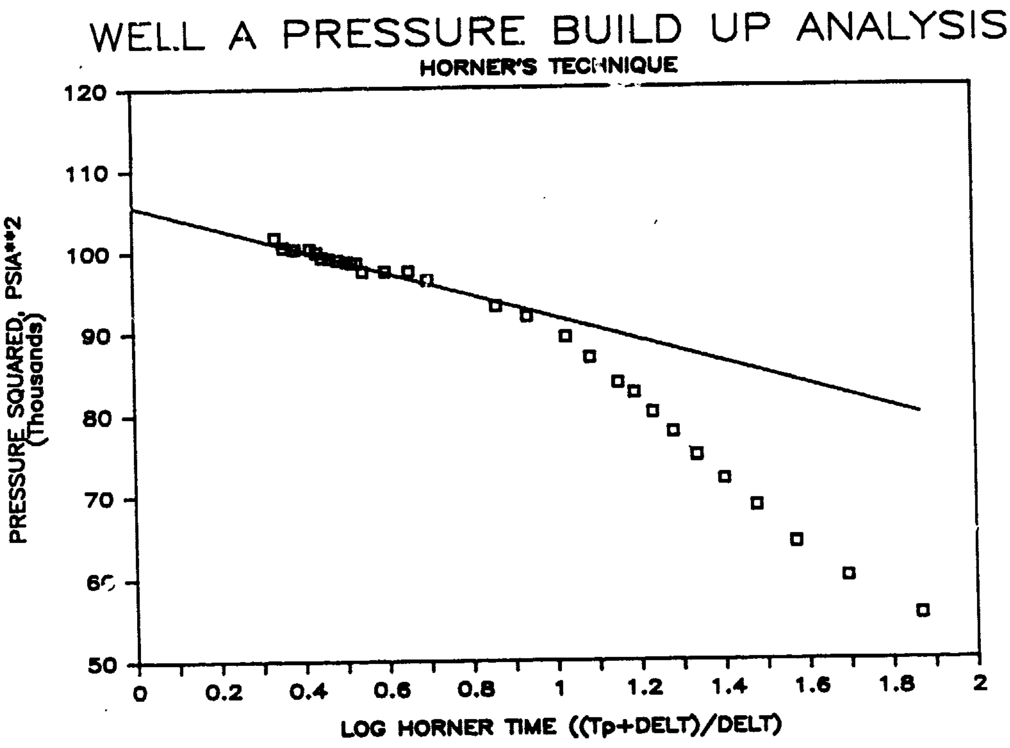

Figure 3: Horner Plot Using Pressure Squared vs. Time Data for Vertical Well A

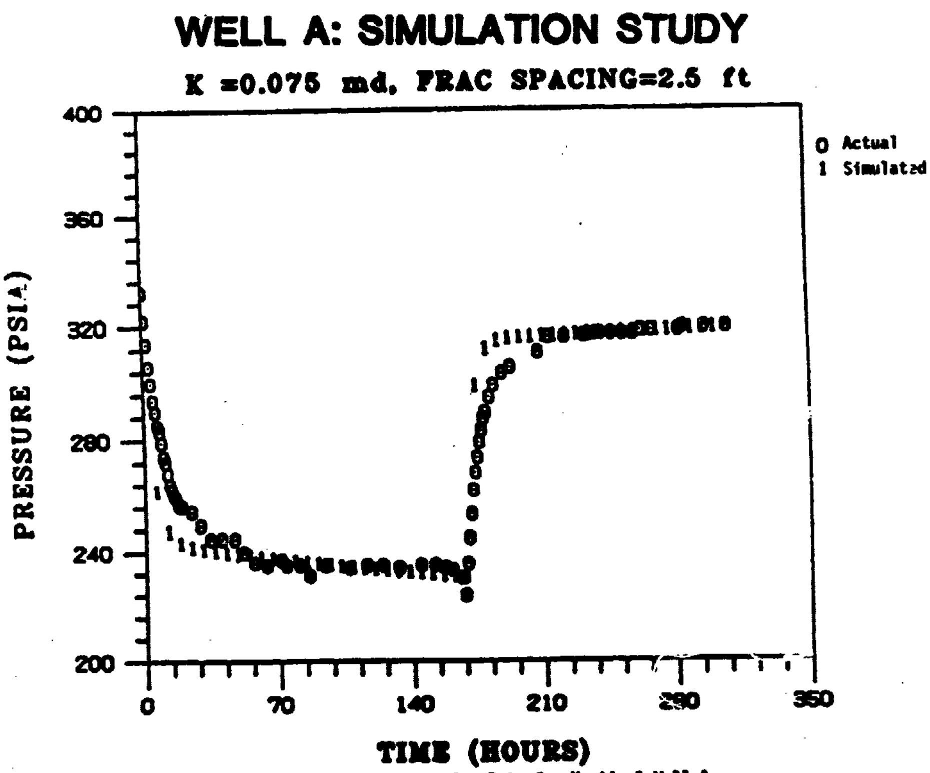

Figure 4: History Match of Pressure-time Data for Vertical Well A

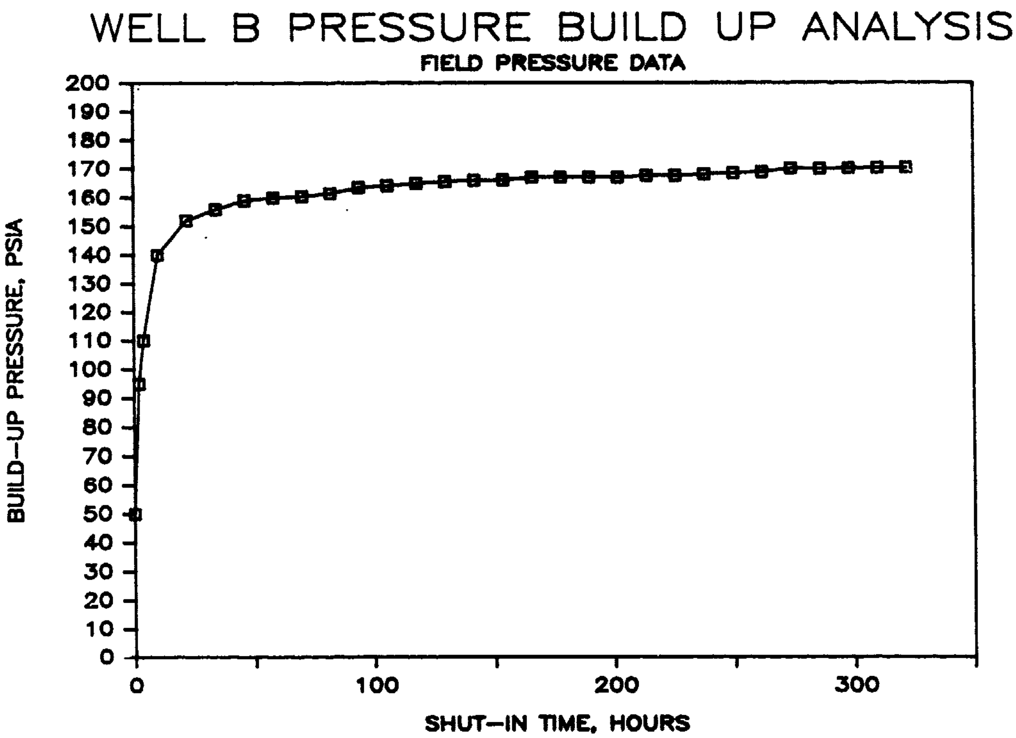

Figure 5: Field Build-up Pressure-time Data for Horizontal Well B

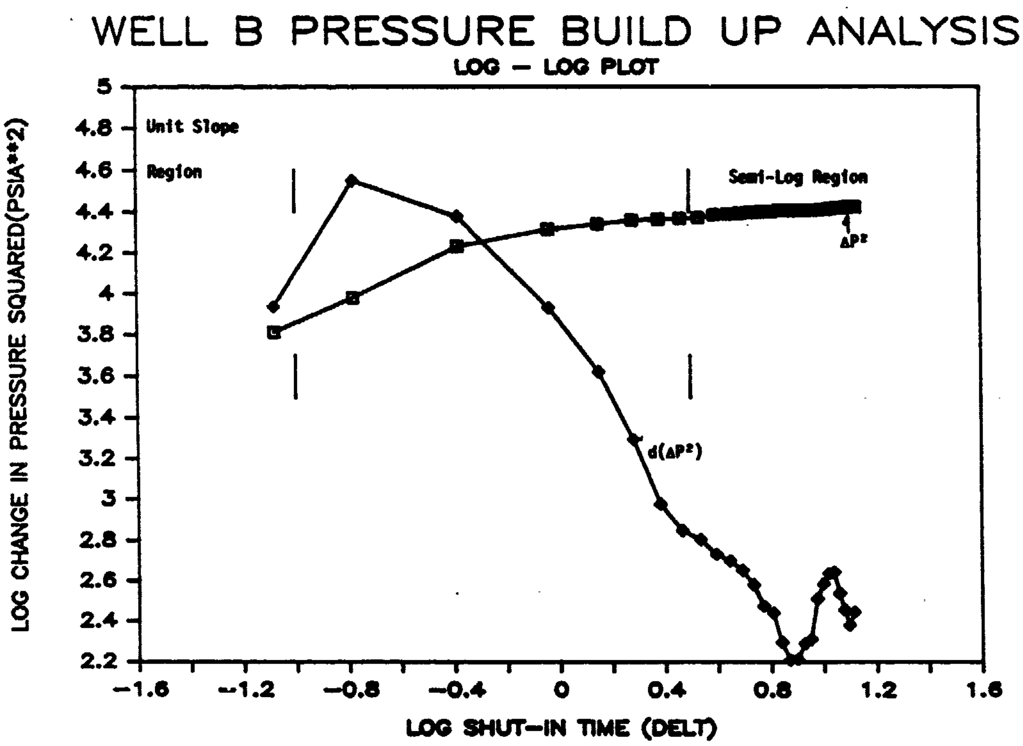

Figure 6: Log-Log Pressure-Squared and Pressure-Squared Derivatives: Well B

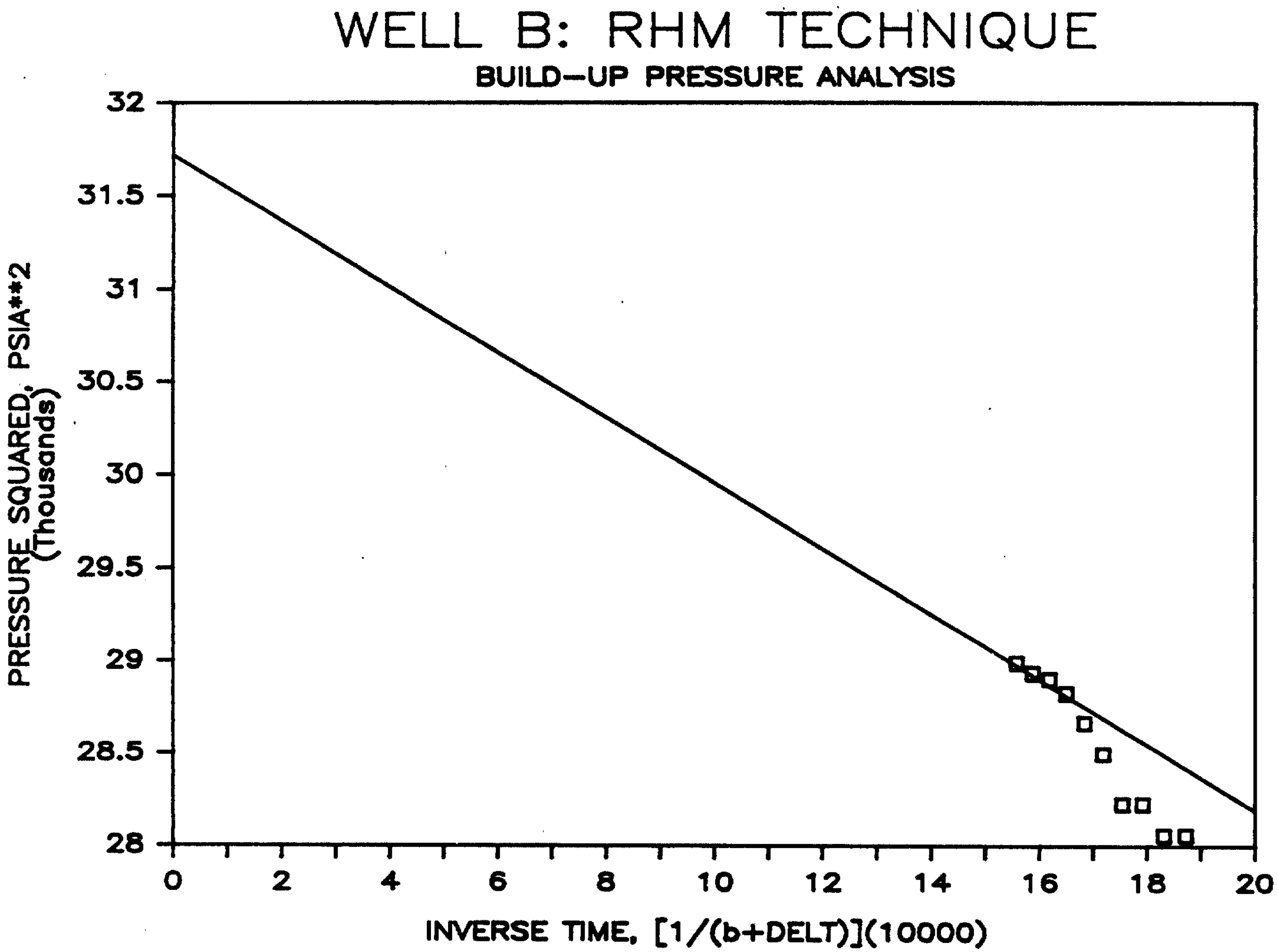

Figure 7: RHM Plot for Horizontal Well B

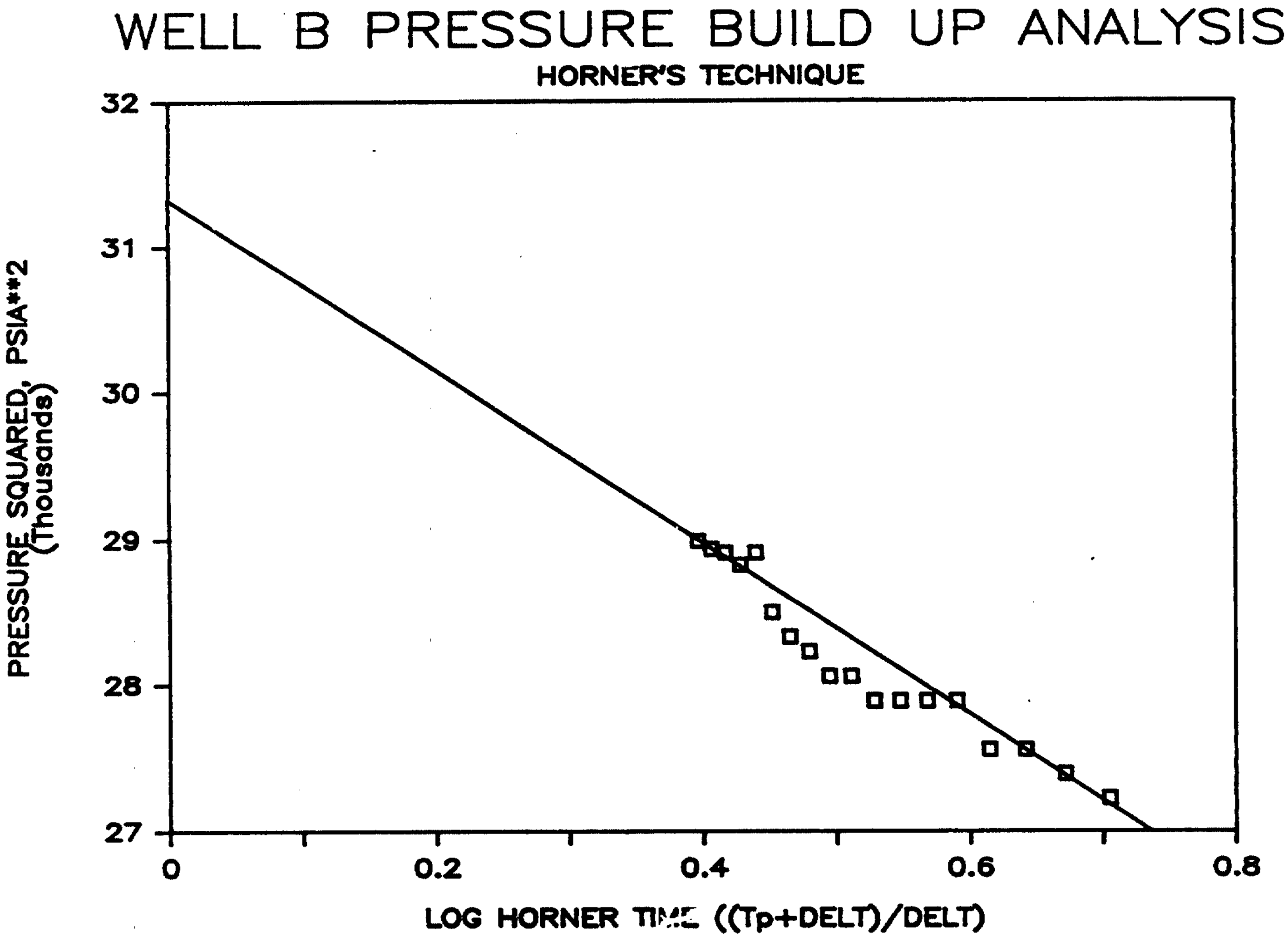

Figure 8: Horner Plot Using Pressure Squared vs. Time Data for Horizontal Well B